BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

IN THE MATTER OF THE APPLICATION OF PUBLIC SERVICE COMPANY OF NEW MEXICO FOR REVISION OF ITS RETAIL ELECTRIC RATES PURSUANT TO ADVICE NOTICE NO. 667	)	**Docket No. 26-0000XXX**
PUBLIC SERVICE COMPANY OF NEW MEXICO,	)	
Applicant.	)	

DIRECT TESTIMONY

OF

ASLAM T. HAYAT

November 24, 2026

NMPRC DOCKET NO. 26-0000XXX
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WITNESS FOR
PUBLIC SERVICE COMPANY OF NEW MEXICO

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ABBREVIATION	DESCRIPTION OF ACRONYM OR ABBREVIATION
Base Period	July 1, 2025, through June 30, 2026
CD	Cooling degree. Degrees above a base temperature on a day
CDD	Cooling degree days. Sum of cooling degrees in a month or year
COT	Customer owned transmission
CP	Coincident peak. Customer or class load at time of system peak
DBT	Drybulb temperature
Demand Ratio	Maximum demand divided by average load (inverse of load factor)
EIA	Energy Information Administration, U.S. Department of Energy
EV	Electric Vehicle
GHI	Global horizontal irradiation measured in Watts per square meter
GWH	Gigawatt hour. 1,000 MWh
GP	General Power customer class
HB	Hour beginning (for example 15:00 for 3 PM to 4 PM)
HD	Heating degree. Degrees below a base temperature on a day
HDD	Heating degree days. Sum of heating degrees in a month or year
KWH	Kilowatt hour
KW	Kilowatt
KVA	Kilovolt ampere
Load Factor	Average hourly energy divided by peak load
LED	Light Emitting Diode
LP	Large Power customer class
LS	Large Service customer classes
MWH	Megawatt hour. 1,000 KWH
MW	Megawatt. 1,000 KW
MVA	Megavolt ampere. 1,000 KVA
NCP	Non coincident peak. The maximum load for a customer or class
PAL	Private Area Lighting
PV	Photo voltaic, usually meaning behind-the-meter solar
Pri	Abbreviation for Primary voltage
2024 Rate Case	Case No. 24-00089-UT
2026 Rate Case	The current rate case
RKVA	Reactive power in kilovolt amperes
RMVA	Reactive power in megavolt amperes
SAE	Statistically Adjusted End-Use modeling approach
Sales	Net delivered energy (delivered - received)
Sec	Abbreviation for Secondary voltage
SP	Small Power customer class
SPCD	Sales per customer per day

SPD	Sales per day
Test Period	October 1, 2027, through September 30, 2028
TOD	Time-of-Day
TOU	Time-of-Use
UPCD	Energy use per customer per day (regardless of source)
UPD	Energy use per day (regardless of source)
Use	Electricity consumed by customer end-use equipment
WHEV	Whole House Electric Vehicle Pilot. Part of rate 1A.

DIRECT TESTIMONY OF
ASLAM T. HAYAT
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I. INTRODUCTION AND PURPOSE

Q. Please state your name, position, and business address.

A. My name is Aslam T. Hayat. I am Manager, Load Forecasting, for Public Service Company of New Mexico ("PNM" or "Company"). My business address is 414 Silver Ave. SW, Albuquerque, New Mexico 87102. I am testifying on behalf of PNM.

Q. Please describe your position with PNM and your qualifications.

A. As PNM's Manager of Load Forecasting, I am responsible for directing and supporting PNM's load forecasting activities, including forecasts for customer counts, energy sales, peak demand, load shapes, and related billing determinants used for rate cases, integrated resource planning, annual operating plans, and other utility planning needs. My responsibilities include overseeing forecasting methodologies, reviewing historical sales and load data, evaluating weather-normalization assumptions, incorporating customer growth and economic development inputs, supporting load research and rate design analyses, and coordinating with internal PNM subject matter experts to ensure that forecast assumptions are reasonable and appropriately documented. A copy of my resume is attached as PNM Exhibit ATH-1.

Q. Have you testified previously in any proceedings before the New Mexico Public Regulation Commission ("Commission" or "NMPRC")?

A. No, I have not testified in any cases before the Commission.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to discuss the data and modeling methods that PNM used to develop both the Base Period estimates and Test Period projections that support the Company's cost allocation and rate design calculations in this rate case. The Test Period projections that I discuss result in billing determinants and allocators (e.g., coincident and non-coincident peaks) that PNM used to allocate costs and create the proposed rates for the Company's retail rate classes.

Q. Please describe the Base Period in the context of your testimony.

A. The Base Period is the starting baseline that serves as a snapshot of historical data used in a rate case. For this rate case, the Base Period is the 12-month period from July 1, 2025, through June 30, 2026. For this period, historical sales and hourly load data are analyzed and modeled to develop the following:

- Weather adjustments for customer class sales in the Base Period;
- Estimates of customer hourly loads, which are used to determine class peaks and loads at the time of the system peaks.

The Base Period results provide the starting point for development of projections in the Test Period.

Q. How does the weather adjustment modeling approach used in this case compare to PNM's last rate case?

A. The approach used to calculate weather adjustments in this rate case is the same as was used in PNM's most recent rate case, Case No. 24-00089-UT ("2024 Rate Case"). Specifically, in this current case normal weather is based on the recent 10 years of actual weather that is 2015 through 2024. This weather data is also consistent with the data supporting the load forecast developed for the 2026 IRP.[1]

Q. Why does PNM use estimates for Base Period customer hourly loads?

A. The Company uses estimates because PNM does not currently have the metering infrastructure to measure individual hourly usage for all customers. Thus, the Company estimates class hourly loads and peaks at the meter level using a representative sample for each rate schedule that indicates the aggregated class loads.

These class usage estimates are critical to the ratemaking process because they help identify when and to what extent each customer class uses and benefits from the electric system, particularly during periods that drive system costs. This information helps determine cost causation by identifying which customer classes benefit from and contribute to the need for generation, transmission, and distribution capacity. In turn, those usage patterns help inform how the costs of providing service are allocated among customer classes and support the

[1] *See* https://www.pnm.com/2026-irp. To ensure consistent evaluation of the information before the Commission in various proceedings, PNM is using the same data for weather as what was filed in the 2026 IRP. *See* 2026 IRP at Appendix H, p. H-7, noting that weather normalization used a 10-year normal period of 2015 to 2024.

development of the individual rates necessary to recover those costs during the Test Period from all retail classes.

Q. Please describe the Test Period in the context of your testimony.

A. The Test Period is the 12-month period for which rates are being designed in this rate case, that being October 1, 2027, through September 30, 2028. Test Period projections are developed for the following:

- Number of customers by customer class and rate schedule.
- Billing determinants by rate schedule.
- Estimates of customer class hourly loads, to determine class peaks and system peaks.

Q. Please provide a high-level summary of your testimony to aid in navigation of the matters addressed.

A. My testimony is organized as follows:

- Section II of my testimony starts by providing the basics of load forecasting, which describes what load forecasting is and how it is used for purposes of determining rates in a rate case. This section also describes how I conducted my load forecast, including the scope of information included in this forecast.
- Section III of my testimony provides Base Period and Test Period data for PNM's customer classes and rate schedules.
- Section IV of my testimony described how PNM models monthly customer class sales.

- Section V of my testimony describes how PNM determined the Base Period weather adjustments.
- Section VI of my testimony explains the derivation and results of the customer growth forecasts.
- Section VII of my testimony details the Test Period sales, as well as the overall change in customer class sales from the Base Period to the Test Period.
- Section VIII of my testimony sets forth the framework for how PNM conducts hourly load projections and describes how the hourly load data is used.
- Section IX describes how class load projections are used to project system loads and how the class coincident peak results are computed.
- Section X details the process of deriving billing determinants, which are then used by PNM to determine rates by rate schedule.

Q. Are you sponsoring any Rule 530 schedules?

A. Yes. I sponsor the following Rule 530 Schedules:

- M-3: Demand and Energy Loss Factors
- P-1: Peak Demand Information
- P-5 : Retail Customer Information
- P-6: Weather Data
- P-9: Line Loss Information
- Q-1: Load Research Program

II. BASICS OF LOAD FORECASTING

Q. What is load forecasting?

A. Load forecasting is the process of projecting future electricity requirements, including customer energy sales and peak demands. The forecast considers historical electricity usage, customer growth, weather, economic conditions, energy efficiency, behind-the-meter solar, electric vehicle adoption, large customer developments, and other factors that may affect future electricity consumption. The resulting forecast based on the changes in the above-mentioned factors projects energy requirements, typically expressed in megawatt-hours, and peak demand, expressed in megawatts. These forecasts support utility planning activities such as resource planning, transmission and distribution planning, budgeting, and other operational and regulatory needs, including rate cases.

Q. How is load forecasting used in rate cases?

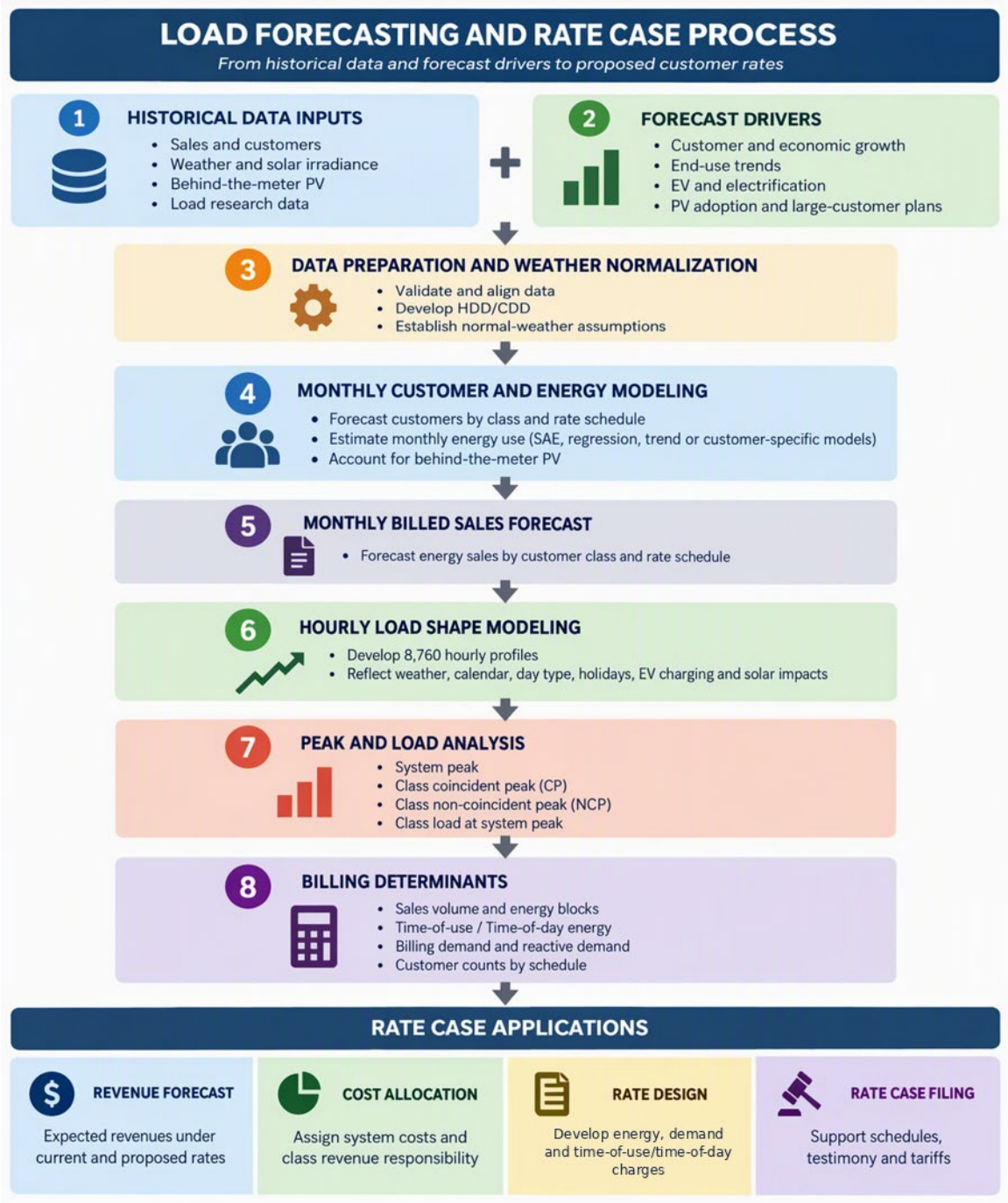
A. Load forecasting provides different inputs for different stages of the ratemaking process. For rate design, the forecast establishes billing determinants, including forecasted energy sales and other applicable billing estimates, that are used to translate a class revenue requirement into proposed rates.

Additionally, the forecast provides hourly class loads that reflect the timing and magnitude of each retail class's use of the electric system. Those hourly loads allow PNM to evaluate class usage during the specific hours or periods relevant to various cost-allocation methodologies. For example, where an allocator considers

contribution to system peak demand, the hourly forecast can be used to determine each class's demand during the applicable peak period. This helps establish how the costs associated with serving system demand should be assigned among retail customer classes.

PNM Figure ATH-1 below demonstrates the load forecasting workflow in visual form.

PNM Figure ATH-1
Workflow of Forecasting



Q. How are class loads and billing determinants used in the rate making process?

A. PNM uses Test Period projections of customer class hourly loads and class loads at the time of system peaks in cost allocation calculations that drive the assignment of revenue requirements by class. PNM also uses Test Period projections of monthly billing determinants to calculate the proposed rates that result in the requested revenue requirement.

The modeling approach used to generate the Test Period results is essentially the same as in the 2024 Rate Case but includes certain updates to load shapes and the projected loads for large commercial service and industrial customers. The minor changes mentioned above, when compared to the modeling approach used in the 2024 Rate Case, include:

- Calculating projected hourly loads for Rate Schedule 1B for the residential customers participating in the Time-of-Day ("TOD") Pilot.
- Calculating projected hourly loads for Rate Schedule 2B for the small power customers participating in the TOD pilot.
- An update to forecasts of sales growth for existing commercial and industrial customers to incorporate information provided by the customers based on quarterly updates from customers.
- An update to the projected load growth related to economic development based on the most recent information as of July 2026. In this case, there are customer additions and load expansions for certain customers served under select Large Service rate schedules.

My testimony below provides an overview of the analysis and modeling methods that PNM used to develop Test Period data, along with tables and charts that present the high-level results.

III. CUSTOMER CLASSES AND RATE SCHEDULES

Q. Please define "customer class" as it is used in your testimony.

A. Customer classes are high level groupings based on customer type, customer size, and the voltage level at which energy is delivered. PNM Table ATH-1 below provides a list of the customer classes and their definitions. It also provides Base Period data for the number of customers, annual sales in gigawatt hours ("GWh"), annual sales per customer ("SPC") in MWh, and the percentage of total sales for each class. The customer and sales data are measured with historical data from PNM's customer billing system for the months in the Base Period. Sales are measured in kilowatt hours ("KWh") at the customer premises by electric meters. In my testimony, SPC values are reported in MWh (MWh = 1,000 KWh) and sales levels are reported in GWh (GWh = 1,000 MWh).

PNM Table ATH-1
Base Period Customer Class Data

Class Definition	Customer Class	Rates	Average Customers	Annual Sales (GWh)	Sales Per Customer (MWh)	Percent of Sales (%)
Residential	Res	1A, 1B	499,470	3,233.6	6.5	33.1%
Small Power	SP	2A, 2B	54,766	931.0	17.0	9.5%
General Power	GP	3B to 3F	4,313	1,888.8	437.9	19.4%
Large Power	LP	4B	155	858.5	5,539.2	8.8%
Large Service	LS	5B, 15B, 30B, 33B, 35B, 36B	9	2,609.6	289,952.5	26.7%
Irrigation	Irr	10A, 10B	315	23.9	75.8	0.2%
Water and Wastewater	Water	11B	152	173.0	1,135.2	1.8%
Private Area Lighting	PAL	6		11.7		0.1%
Streetlights	SL	20	277	30.6	110.8	0.3%
Total All Classes			**559,457**	**9,760.6**	**17.45**	**100.0%**

Q. Please define the terms "rate schedules" and "billing determinants" as they are used in your testimony.

A. Rate schedules divide customer classes into more specific groupings. Rate schedules define the specific tariffs for each grouping within a customer class. For example, the residential customer class includes two rate schedules: Rate 1A for standard residential service, and Rate 1B for the TOD Pilot applicable to residential customers. PNM Table ATH-2 below provides a list of the rate schedules for which Test Period billing determinant projections are made. This table also shows the specific billing determinants that are used for each rate schedule. In addition to the billing determinants shown in the table, all non-lighting rate schedules also include a monthly customer charge. Finally, for the Large Power ("LP4") class, there is a distinction between customers who have customer-owned transformers (4B-COT)

and customers served by PNM-owned transformers. For streetlighting (SL20), billing determinants are also divided into PNM-owned and customer-owned lighting categories.

PNM Table ATH-2
Rate Schedules and Billing Determinants[2]

Customer Class	ID	Rate Schedule	Description	Energy Charges	On-Peak Demand	Reactive KVA
Residential	Res	1A	Energy by Usage Block	By Block		
		1A-WHEV	Whole House Electric Vehicle	Off Peak		
		1B	Time-of-Day	TOD		
Small Power	SP	2A	Energy	Energy		
		2B	Time-of-Day	TOD		
General Power	GP	3B_S	Secondary	TOU	Yes	Yes
		3B_P	Primary	TOU	Yes	Yes
		3C_S	Secondary, Low Load Factor	TOU	Yes	Yes
		3C_P	Primary, Low Load Factor	TOU	Yes	Yes
Municipal General Power	GP	3D_S	Secondary	TOU	Yes	Yes
		3D_P	Primary	TOU	Yes	Yes
		3E_S	Secondary, Low Load Factor	TOU	Yes	Yes
		3E_P	Primary, Low Load Factor	TOU	Yes	Yes
Commercial Charging	GP	3F	Non-residential charging pilot	TOU		
Large Power	LP	4B	Secondary	TOU	Yes	Yes
		4B COT	Primary			
		4B Transm	Transmission	TOU	Yes	Yes
Large Service UNM	LS	15B		TOU	Yes	
Large Service (>30 MW)		30B		TOU	Yes	Yes
Large Service Stn Pwr		33B		TOU	Yes	Yes
Large Power (>3 MW)		35B		TOU	Yes	Yes
Special Service Renewable		36B		Net Energy	Yes	
Water and Wastewater	Water	11B		TOU/ TOD		
Irrigation	Irr	10A	Energy	Energy		
		10B	Time of Use	TOU		

[2] For the commercial and industrial rate schedules, the TOD Pilot option is calculated as a revenue-neutral rate. For Rate Schedules 1B, 2B and 11B, PNM has separately calculated the TOD Pilot billing determinants.

Q. Do you have any additional pertinent observations regarding the table above?

A. Yes. As shown, all the rate schedules have an energy charge that applies to monthly net energy deliveries (also called monthly "sales" in my testimony). These charges have three forms: energy, energy by usage block, and energy by time-of-use/TOD period. There are two or three time-of-use or TOD periods, named on peak, off peak and, where applicable, super off peak.[3] For most of the larger customer classes, there is also a demand charge, which is measured in kilowatts ("KW") representing the highest level of demand in the on-peak period. Most of the large rate schedules also have an additional charge for reactive power, measured in kilovolt amps ("KVA"), that applies to certain customers who have a power factor below a specified level.

As mentioned above, there are two rate schedules for the residential customer class. Rate Schedule 1A is standard residential service and applies to most of the residential customers and includes a different price for each of three usage blocks.[4] For customers in the 1A-WHEV (Whole House Electric Vehicle Pilot), there is an alternative energy charge for usage during the charging hours between 10 p.m. and 5 a.m. on all days. The residential class also has a small fraction (about .02%) of customers on the legacy time-of-use ("TOU") rate schedule in Rate Schedule 1B.

[3] The legacy time-of-use rates have two periods, which includes an on-peak period of 8 a.m. to 8 p.m. Monday through Friday and an off-peak period which are all other hours. The TOD Pilot has three periods, that being on-peak hours, off-peak hours and super off-peak hours.

[4] The first block has the lowest price for usage up to and including 450 KWh. The second block has a higher price for usage over 450 KWh up to and including 900 KWh. The third block has the highest price for usage over 900 KWh.

PNM proposes to transfer all legacy TOU customers to the TOD Pilot in the Test Period. Under this proposal, all legacy TOU rate schedule customers in Rate Schedule 1B will be transferred to the TOD Pilot. Thus, for purposes of the Test Period, PNM is projecting that all legacy TOU customers will be taking service pursuant to the TOD Pilot. The small power ("SP") class has a similar pair of rate schedules (Rate Schedules 2A and 2B), but there are no usage blocks in Rate Schedule 2A. Similarly, the irrigation class has two rate schedules, Rate Schedule 10A has a simple energy charge and Rate Schedule 10B that has energy by TOU.

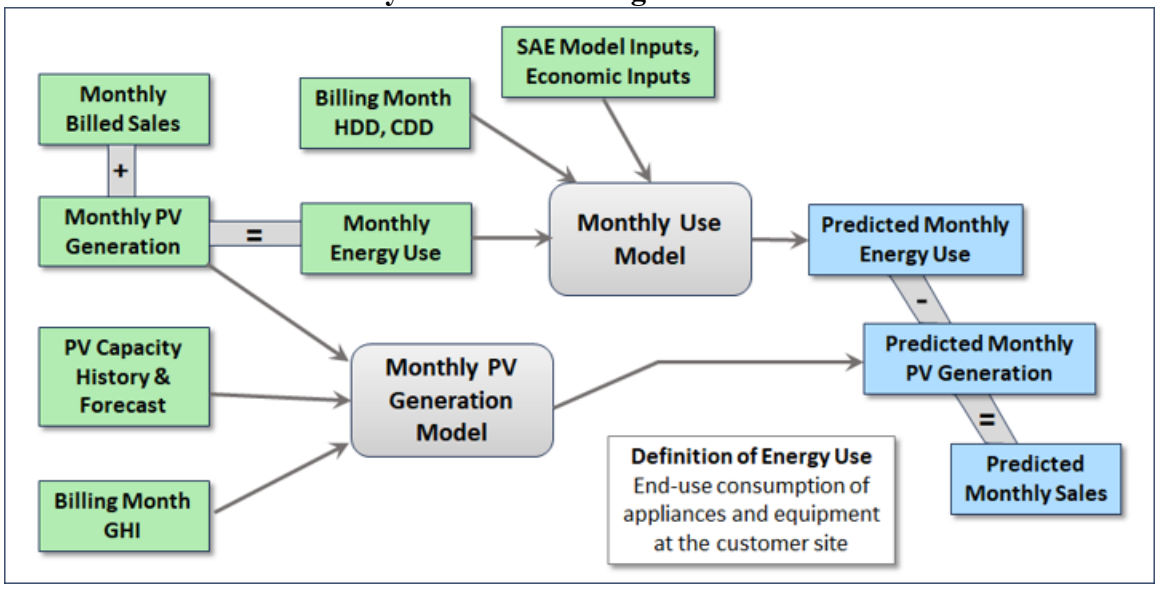
For the general power ("GP") class, rate schedules are split into five categories. Rate Schedules 3B and 3C are for non-municipal customers with regular load factors (3B) and low load factors (3C). Rate Schedules 3D and 3E are for municipal customers with regular load factors (3D) and low load factors (3E). In later figures that present billing determinant data, all four of these categories are further split into secondary ("Sec") and primary ("Pri") categories depending on the voltage level at which power is delivered (for example, 3B-Sec and 3B-Pri). Finally, there is a pilot Rate Schedule 3F for commercial electric vehicles charging sites.

IV. MONTHLY CUSTOMER CLASS SALES MODELING FRAMEWORK

Q. Can you provide a summary of the approach that is used to model monthly customer class sales?

A. PNM projects monthly sales by customer class using statistical models that incorporate historical sales, weather, and distributed solar generation data. The models are applied to normalized weather conditions during the Base Period to forecast sales for the Test Period. PNM Figure ATH-2 illustrates PNM's monthly sales modeling framework, which is consistent with the methodology used in the 2024 Rate Case.

PNM Figure ATH-2
Monthly Sales Forecasting Framework



Q. How is behind the meter solar photovoltaic ("PV") generation treated in the framework?

A. Behind-the-meter solar PV systems have significantly reduced billed electricity sales, particularly in the residential class. Because PV generation can be either consumed on-site or exported to the grid, it both lowers billed sales and obscures actual customer electricity usage. To address this effect, PNM's forecasting

framework explicitly accounts for solar generation. Approximately 98 percent of solar customers have production meters that directly measure PV output, eliminating the need to estimate historical generation. Measured monthly PV generation is added to billed sales to calculate total monthly energy use, which reflects actual end-use consumption and forms the basis of the Monthly Use Models presented in PNM Figure ATH-2.

Q. How does PNM calculate the predicted values for PV generation?

A. Although measured PV generation data is available for the Base Period, it is necessary to develop generation predictions for the Test Period. This is represented in the lower left-hand portion of PNM Figure ATH-2, which shows the inputs to the monthly PV generation model. This is a regression model that explains variations in measured monthly generation. The main explanatory factor is global horizontal irradiation ("GHI"). GHI values are included in the historical hourly weather data, which is acquired from AccuWeather, a widely recognized vendor of quality weather data. Hourly GHI data for four PNM weather stations (Albuquerque, Alamogordo, Deming, and Santa Fe) are weighted together and then summed to the daily level. For each month, these daily GHI values are then summed across the days in each billing cycle. This process aligns the GHI values that occurred during the monthly billing cycles with the PV generation that occurred over these cycles. The estimated model is then used to project hourly, daily, and monthly PV generation for the Test Period, based on growth in installed PV capacity and a normal pattern for GHI values.

Q. How are overall predicted values for PNM monthly sales calculated?

A. As shown in PNM Figure ATH-2, the monthly energy models explain monthly energy use, computed as the sum of measured monthly sales and measured PV generation. As will be discussed later in the testimony, the models are usually in the form of use per customer ("UPC") or use per customer per day ("UPCD"). As shown in the figure, after monthly use is projected, the predicted values for monthly PV generation are subtracted, providing the estimate for predicted monthly sales. For the classes that have no on-site PV, the numbers for monthly use and sales will be the same. For the classes that do have on-site PV, monthly use will be a larger number than monthly sales.

Q. How are end use equipment saturation and efficiency treated in the framework?

A. The framework uses Statistically Adjusted End-Use ("SAE") models for the residential and commercial classes (SP, GP, and LP). This method was developed by the Itron forecasting team to utilize end-use inputs in an econometric framework. This approach is widely used by utilities and system operators in North America. The essence of the approach is to develop saturation and efficiency assumptions for a list of appliance and equipment types and combine these assumptions into three index variables for heating, cooling, and other uses. The heating index interacts with monthly weather variables for cold weather (heating degree days or "HDD"). The cooling index interacts with monthly weather variables for warm weather (cooling degree days or "CDD"). The model also includes seasonal variables, time-

trend variables, and variables that represent several phases of the COVID-19 pandemic.

The end-use inputs for the SAE model are based on data released as part of the Annual Energy Outlook, which is published each year by the Energy Information Administration ("EIA"), part of the U.S. Department of Energy. These data are provided by region; for PNM, the Mountain Region data are used as a starting point. For PNM, evaporative cooling is added to the list of cooling technologies. For all end uses, market data from the Demand Side Management ("DSM") Potential Study are used to adjust saturation levels and energy intensity levels to represent the end-use mix and conditions in the PNM service territory. The DSM Potential Study provides PNM-related information for end-uses such as Water heating, Space cooling, Space heating, Ventilation, Lighting, Other etc. Finally, energy use projection for electric vehicle ("EV") adoption in the PNM territory are added to the group of end uses that are not weather sensitive.

The SAE modeling approach is specifically designed for models of energy use. The SAE inputs combine to provide a projection of the energy use of appliances and equipment. Therefore, energy use (not utility sales) is the appropriate variable for the SAE model to explain.

Q. Please describe other features of the monthly sales models.

A. The methods used to model energy use vary across classes and are summarized in PNM Table ATH-3. As shown in the table, models for Residential, SP, GP, and LP4 are configured to predict monthly use per customer per billing day ("UPCD"). These models use the SAE approach described earlier and therefore include detailed end-use inputs as well as monthly weather variables. Forecasts from these models are multiplied by the forecasted number of customers and the number of billing days in the month to provide energy use forecasts, and projected PV generation is then subtracted to provide billed sales forecast.

PNM Table ATH-3
Summary of Modeling Methods

Class Definition	Customer Class	Rate Schedule	Use or Sales Per Day	Use Per Cust Day (UPCD)	SAE	Solar	Usage Model	Customer Model	Sales Adjust
Residential	Res	1		Yes	Yes	Yes	Regression	Smoothing	
Small Power	SP	2		Yes	Yes	Yes	Regression	Smoothing	
General Power	GP	3		Yes	Yes	Yes	Regression	Regression	
Large Power	LP	4		Yes	Yes	Yes	Regression	Smoothing	Yes
Large Service (>8MW)	LS	5	SPD				Regression		
Large Service University	LS	15	UPD			Yes	Regression		Yes
Large Service (>30MW)	LS	30	SPD				External		Yes
Large Service Stn Pwr	LS	33	SPD				Regression		
Large Power (>3MW)	LP	35	SPD				Regression		Yes
Special Service Renewable	LS	36					External		Yes

Class Definition	Customer Class	Rate Schedule	Use or Sales Per Day	Use Per Cust Day (UPCD)	SAE	Solar	Usage Model	Customer Model	Sales Adjust
Irrigation	Irr	10	UPD			Yes	Regression		
Water and Wastewater	Water	11	UPD			Yes	Regression		
Private Area Lighting	PAL	6					Lamps		
Streetlights	SL	20					Lamps		

For most of the large customer classes (LS5, LS15, LS33 and LP35), either regression or exponential smoothing models are used to predict sales per day ("SPD") or use per day ("UPD"), depending on the presence of solar PV. The regression models include monthly constant terms to account for seasonality and shift variables to account for the impact of COVID-19 phases. For two of the large customer classes (LS30 and LS36), external forecasts provided by the customer are used to drive the sales forecast. Adjustments to the model-based forecast were made for LS15 and LP35 based on input from the customers about expected operational changes. Finally, upward adjustments were included for LP4 and LP35 to reflect expected new customer additions related to PNM economic development activities.

Regression models are also used for the Irrigation customer class (Rate Schedule 10) and the Water and Wastewater class (Rate Schedule 11). These models have monthly constants to account for seasonal patterns and time trend variables to capture growth trends in energy use.

Finally, the predictions developed for the Private Area Lighting (Rate Schedule 6) and Streetlighting (Rate Schedule 20) classes are based on detailed fixture projections with specific assumptions about the number of lighting fixtures and type of lamp in each fixture. Energy forecasts for the lighting classes are provided by PNM and reflect specific assumptions about changes in lamp types toward more efficient lamp options, such as light emitting diodes ("LED").

Q. Are the monthly use and sales models used by PNM for anything other than the rate case?

A. Yes, they are. The same modeling framework is used to provide the customer and monthly sales forecast for the AOP ("Annual Operating Plan") and the long-term forecasts for the Integrated Resource Plan ("IRP"). For the IRP, the model forecasts extend through 2042, and the SAE framework is used to quantify the impact of alternative economic growth and electrification scenarios.

Q. Is PNM Revising its loss factors in this rate case?

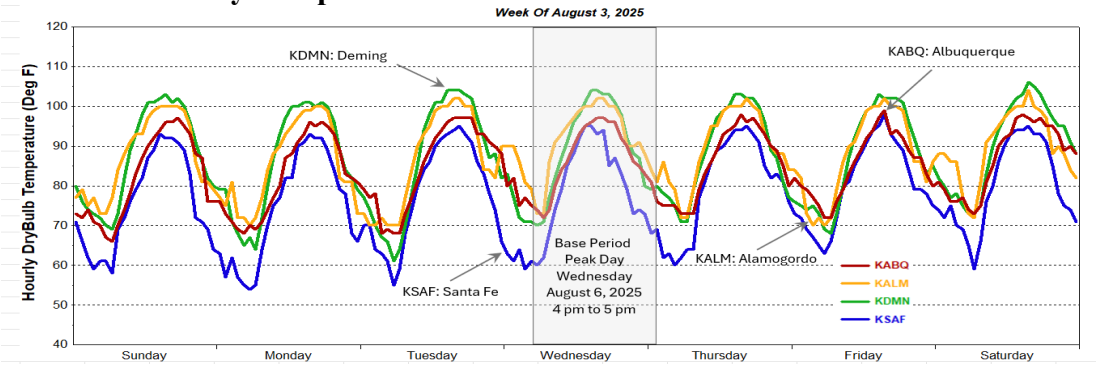
A. Yes. PNM is revising the loss factors that reflect the relative energy losses for each class for the Test Period. The Transmission and Distribution Planning Department at PNM has recalculated the energy and demand losses of the system in 2026 based on a loss study. Given that information the Test Period losses by voltage level are different from losses used in the 2024 Rate Case, the loss factors were modified in this case as reflected in 530 Schedule M-3.

V. BASE PERIOD WEATHER ADJUSTMENTS

Q. Can you summarize the weather data that are used to calculate Base Period weather adjustments?

A. Hourly weather data were acquired for Albuquerque (KABQ), Alamogordo (KALM), Deming (KDMN), and Santa Fe (KSAF) weather stations from AccuWeather for the most recent 10 years including the Base Period. For each station, two of the hourly data series are used in the analysis: hourly drybulb temperature ("DBT") in degrees Fahrenheit and global horizontal irradiation ("GHI") measured in Watts per square meter. The hourly data for DBT are shown in PNM Figure ATH-3 for the summer peak week in the Base Period.

PNM Figure ATH-3:
Hourly Temperature Data for Base Period Peak Week



Q. How are the hourly weather data converted to variables used in daily models?

A. Hourly temperature data are processed in the steps outlined below. First, for each station, the daily average temperature for each day is computed by averaging the

24-hourly values for that day. These daily average values are used to compute cooling degrees ("CD") and heating degrees ("HD") for each day.

Cooling degrees are the number of degrees *above* a base temperature level. For example, cooling degrees base 70 ("CD70") is the number of degrees above 70. The warmer it is, the bigger this value will be. Similarly, heating degrees are the number of degrees below a base temperature. The colder it is, the bigger this value will be. PNM's standard practice is to compute daily HD and CD values with multiple base values. Cooling degrees with base temperatures of 55, 60, 65, 70, and 75 are computed for each station on each day. Heating degrees with base temperatures of 60, 55, 50, and 45 are computed for each station on each day.

After the values are computed, the daily CD values are weighted across stations using shares of summer month energy as weights. The daily HD values are weighted across stations using shares of winter month energy as weights.

Q. How are daily degree day data converted to variables used in monthly models?

A. When daily values for HD and CD are added across the days in a month or the days in a billing cycle, the sums are called heating degree days ("HDD") and cooling degree days ("CDD"). In my testimony below, HD and CD refer to temperatures on a day, while HDD and CDD refer to temperatures during a billing month or a calendar month. For calendar month calculations, the HD and CD values for a

month are added across the days in the month to give the monthly HDD and CDD values.

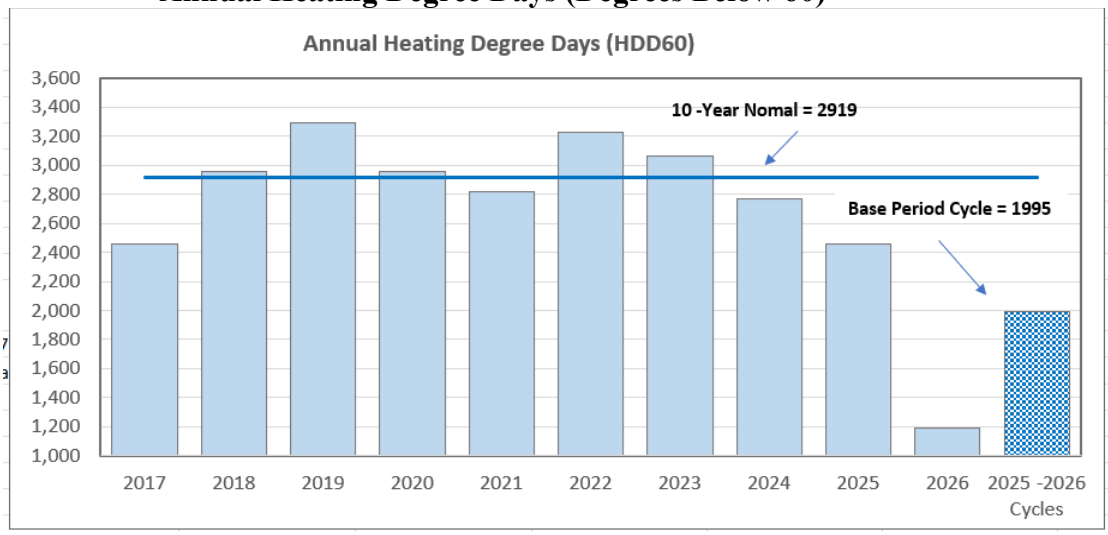
For billing month calculations, the daily HD and CD values are summed across the days in each billing cycle and then combined across cycles to give a billing month HDD value for each heating base temperature and a billing month CDD value for each cooling base temperature. These billing month sums reflect the weather that occurred on the days that are included in billed sales in each billing month. Appropriate alignment of the weather data with the monthly sales and use data is extremely important for model estimation, and the steps above ensure that this is an "apples-to-apples" relationship.

Q. For this rate case, how did actual weather in the Base Period compare to normal values?

A. PNM Figure ATH-4 shows the annual sum of monthly HDD values computed from a base temperature of 60 degrees for the period from 2015 through 2024. While my modeling relied on this 10-year period data for normal weather, PNM Figure ATH-4 also shows HDD values for 2025 and part of 2026 (through June) for illustrative purposes to validate the 10-year normal weather. The line labeled "Normal" shows the 10-year average as 2,919 degrees. The Base Period actual sum is about 31.6% lower, reflecting warmer than normal weather in February, March, and April of the Base Period. This resulted in lower-than-normal sales related to heating, especially

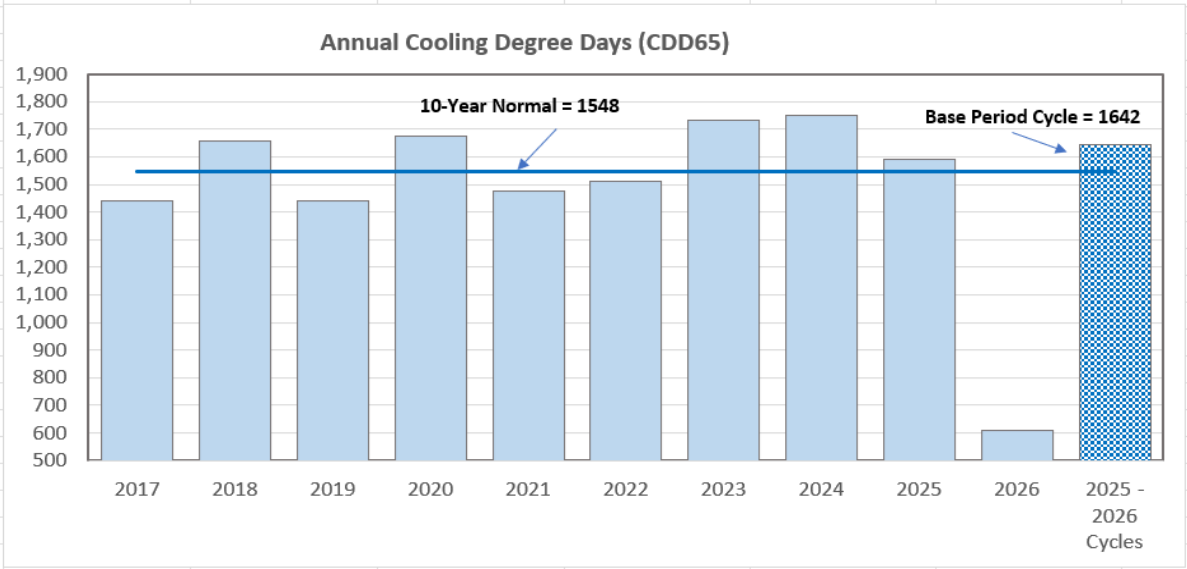
in the residential and small commercial classes, which have the highest sensitivity to cold weather.

PNM Figure ATH-4
Annual Heating Degree Days (Degrees Below 60)



PNM Figure ATH-5 shows the annual sum of monthly CDD values computed from a base temperature of 65 degrees for the 10-year period from 2015 through 2024. While my modeling relied on this 10-year period, PNM Figure ATH-5 also shows CDD values for 2025 and part of 2026 (through June) for illustrative purposes to validate the 10-year normal weather. The line labeled "Normal" shows the 10-year average as 1,548 degrees. The Base Period value is 6.1% higher than the normal value, reflecting hot weather in July, August and September of 2025 and 2026. This had a positive impact on Base Period sales related to cooling for all weather sensitive classes.

PNM Figure ATH-5
Annual Cooling Degree Days (Degrees Above 65)



Q. How do you calculate the Base Period weather adjustments?

A. The models of monthly sales are projected with actual billing month HDD and CDD values. As part of estimation, monthly predicted values are calculated using the actual HDD and CDD values.

As described earlier, the most recent 10 years of daily data are used to construct normal monthly HDD and CDD values for each billing month, based on the days that are included in the cycles for that month. The monthly sales models are used to calculate a second set of monthly predicted values using the normal HDD and CDD values. The difference between the two sets of predicted values is the weather adjustment.

Q. Please summarize the monthly weather adjustments for the Base Period.

A. As described earlier, the summer months in the Base Period were hotter than normal (actual CDD was 6.1% above normal CDD). As expected, the predicted use and sales values that accompanied these hotter actual temperatures are higher than the values predicted for normal weather. This leads to an upward, or positive, adjustment in weather for summer months.

Similar to the summer months, the winter months of the Base Period were warmer than normal (actual HDD was 31.6% lower than normal HDD). As expected, predicted use and sales values with these warmer temperatures are lower than predicted values with normal temperatures. This leads to a downward, or negative, weather adjustment for the winter months.

For the Base Period as a whole, the upward sales adjustment from summer and downward sales adjustment from winter combine to give an upward overall weather adjustment. As shown in PNM Table ATH-4, the overall positive adjustment is significant at 67.35 GWh, which is .69% of sales. The largest positive adjustment in percentage terms is 2.89% for the residential class, which is strongly sensitive to both cold and hot weather. Percentage impacts on the commercial classes are in the -1% range.

PNM Table ATH-4
Summary of Base Period Weather Adjustments

Class Definition	Customer Class	Rate Schedules	Base Period Sales (GWh)	Weather Adjust (GWh)	Adjust Percent (%)	Adjusted Sales (GWh)	Percent of Adjusted Sales (%)
Residential	Res	1	3,233.6	93.38	2.89%	3,326.9	33.85%
Small Power	SP	2	931.0	-1.38	-0.15%	929.6	9.46%
General Power	GP	3	1,888.8	-14.09	-0.75%	1,874.7	19.08%
Large Power	LP	4	858.5	-9.89	-1.15%	848.6	8.63%
Large Service	LS	5,15,30-36	2,609.6	-0.65	-0.02%	2,608.9	26.55%
Irrigation	Irr	10	23.9	0.00	0.00%	23.9	0.24%
Water & Wastewater	Water	11	173.0	0.00	0.00%	173.0	1.76%
Private Area Lighting	PAL	6	11.7	0.00	0.00%	11.7	0.12%
Streetlights	SL	20	30.6	0.00	0.00%	30.6	0.31%
Total			9,760.6	67.35	0.69%	9,828.0	100.00%

VI. CUSTOMER GROWTH FORECASTS

Q. Can you summarize the process used to generate customer growth forecasts?

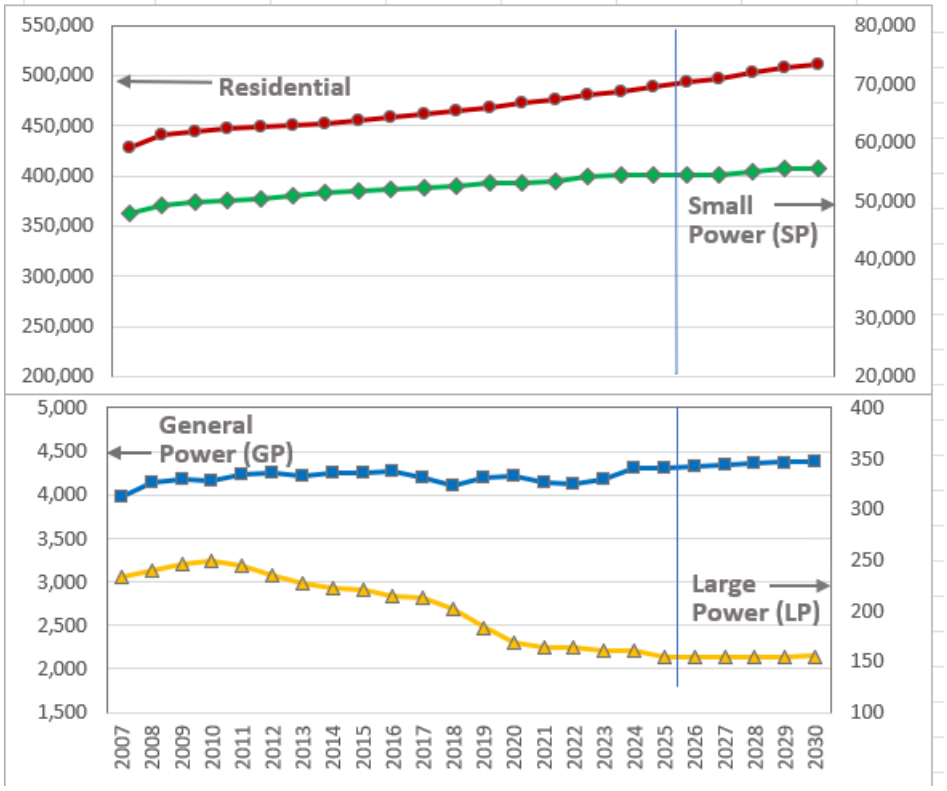
A. Starting with the residential (Res) and small power (SP) classes, exponential smoothing models with a linear trend are used to extend recent customer growth trends out through the end of the Test Period. For the General Power (GP) class, a regression model is used with a geometric weighted index of residential customers and non-manufacturing employment as the explanatory variable.

For the large service rate schedules (Rate Schedules 5B, 15B, 30B, and 36B), the number of customers is held constant in the forecast, with one customer in each rate. Because PNM proposes to remove Rate Schedule 5B, the one remaining Rate Schedule 5B customer is moved to Rate Schedule 4B. Economic Development

assumptions result in the addition of three customers to the Large Power class (Rate Schedule 4B) and the addition of one customer to Rate Schedule 35B.

The customer forecast is best summarized with a graph of the historical and forecast data, which is provided in PNM Figure ATH-6. This figure shows the stable historical growth patterns and the extension of these patterns into the Test Period. Between the Base Period and the Test Period, the growth rate for the residential class averages 0.9% per year, and the growth rate for the small power class averages 0.7% per year.

PNM Figure ATH-6
PNM Customer Count: History and Forecasts



Q. Can you describe how you support the projected loads for the new large load rate schedules, LS37 and LS38?

A. Yes. As discussed by PNM witness Julio C. Aguirre, PNM proposes to add two new rate schedules in this rate case: Rate Schedule 37 (LS37) for large data center loads, and Rate Schedule (LS38) for other manufacturing large loads taking service at transmission level. My testimony supports the amount of load that PNM projects could hypothetically be served under the proposed rate schedules during the rate effective period. The projected load amounts for LS37 and LS38 are both based on a hypothetical new customer load of 75 MW operating at an assumed 90% load factor. These assumptions are used to determine the rates that PNM witness Aguirre supports in testimony for these new rate schedules. The projections for LS37 and LS38 do not impact other customer rates in this case, because PNM is not projecting any billing determinants for these two new rate schedules in this rate case.

VII. TEST PERIOD SALES FORECASTS

Q. Please summarize the overall change in customer class sales from the Base Period to the Test Period.

A. The sales data and forecasts are summarized in PNM Table ATH-5. The table shows Base Period sales, projected Test Period sales, the change in sales and the percent change in sales.

PNM Table ATH-5
Changes in Sales from the Base Period to the Test Period

Class Definition	Customer Class	Rate Schedules	Base Period Sales (GWh)	Test Period Sales (GWh)	Change in Sales (GWh)	Percent Change in Sales (%)
Residential	Res	1	3,233.6	3,392.4	158.8	4.9%
Small Power	SP	2	931.0	957.0	26.0	2.8%
General Power	GP	3	1,888.8	1,930.3	41.5	2.2%
Large Power	LP	4	858.5	982.7	124.3	14.5%
Large Service	LS	15, 30, 33, 35, 36	2,609.6	4,967.8	2,358.3	90.4%
Irrigation	Irr	10	23.9	24.5	0.6	2.5%
Water and Wastewater	Water	11	173.0	166.8	-6.2	-3.6%
Private Area Lighting	PAL	6	11.7	11.4	-0.3	-2.2%
Streetlights	SL	20	30.6	30.5	-0.1	-0.4%
Total All Classes			**9,760.6**	**12,463.6**	**2,702.9**	**27.7%**

In the Test Period, residential sales are projected to increase by about 4.9% relative to actual Base Period sales. Most of this increase comes from residential customer forecast and EV sales growth. The SP and GP customer classes had steady growth in late 2024 and 2025. Sales are expected to follow this trend into the Test Period, with projected increase in both SP sales and GP sales. Positive influences on the SP and GP customer classes include customer growth and expected gains in EV workplace charging and fleet charging.

Gains in the larger classes are even more significant, with LP sales up 14.5% and LS sales up 90.4%. The LP growth reflects the expected addition of new customers which are tracked through economic development efforts. The LS growth primarily reflects expected expansion of operations for the customers in Rate Schedules 30B and 36B and additional customers projected for Rate Schedules 33B.

Irrigation loads are forecast to increase by 2.5%, reflecting an increase due to changes in weather trends. The remaining classes show slight sales declines reflecting continuation of historical trends, as well as increased PV adoption and TOD operation for Water and Wastewater (Rate Schedule 11) and a continuing trend toward more efficient lighting technologies for the lighting classes (Rate Schedules 6 and 20).

Q. Can you explain the change in residential sales for this rate case and comment on how this compares with the projections that were made for the 2024 Rate Case?

A. For the residential class, Test Period sales are projected to increase due to positive customer growth. In particular, increased EV adoption and customer growth with electrification are impacting the current rate case's sales ("2026 Rate Case"). In aggregate, though both EV and PV adoption are still growing, the adoption rate for EVs and PVs is slower when compared to the 2024 Rate Case. As a result, monthly SPC is higher than what was predicted in the 2024 Rate Case forecast due to less energy offset by customer-owned energy production.

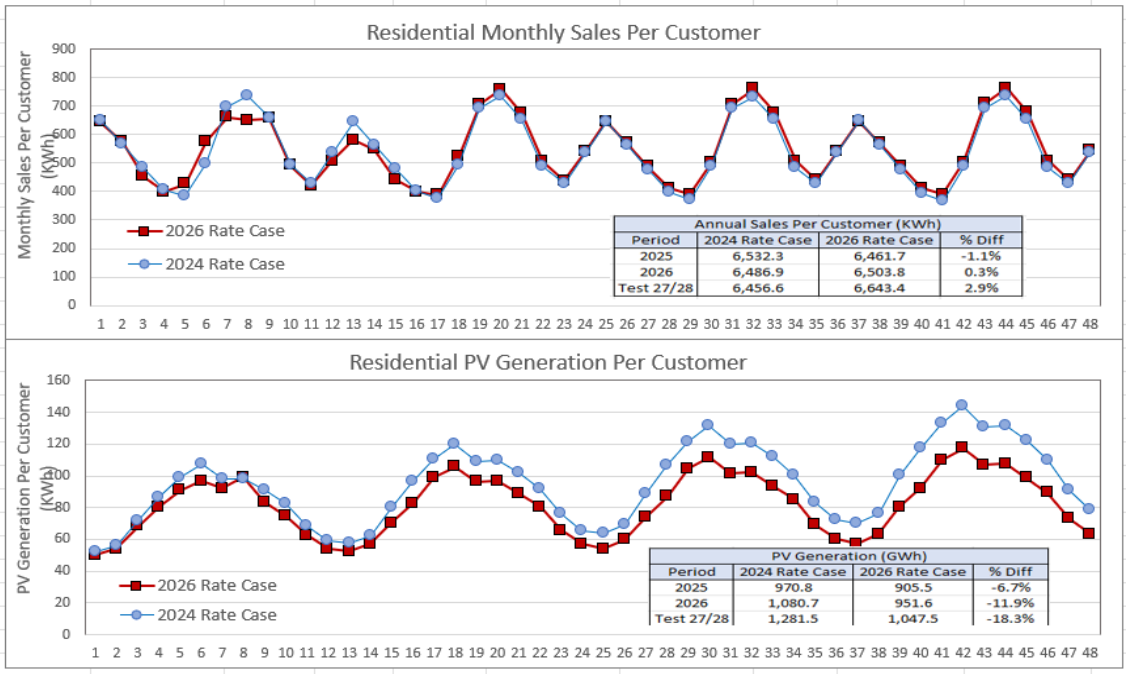
Q. Can you explain why SPC is higher than what was predicted in the 2024 Rate Case?

A. In the 2024 Rate Case, residential SPC values for 2027 to 2028 were projected to decline, driven largely by more PV adoption. By comparison, for this rate case, the 2027 to 2028 forecast monthly SPC is higher than anticipated. This is likely the

result of the fact that PV adoption—which drives down SPC—slowed down significantly, most likely due to the expiration of the federal solar tax credit.

PNM Figure ATH-7 provides a comparison of the forecast data for and of the two rate case forecasts, referred to as the 2024 Rate Case and the 2026 Rate Case. As the top graph of the figure shows, weather adjusted SPC in 2025 came in about -1.1% below the 2024 Rate Case forecast.

PNM Figure ATH-7
Residential Forecast Comparison (KWh Per Customer)



Moving out to the Test Period for the 2026 Rate Case, the updated forecast for SPC is 2.9% above the 2024 Rate Case forecast. This reflects the influence of slower EV adoption and PV adoption for the forecast being used in the 2026 Rate Case as compared to the forecast for the 2024 Rate Case.

The bottom part of the PNM Figure ATH-7 shows the same comparison for forecasts of residential solar generation per customer, measured in monthly KWh per customer. For 2025, the partial actual measured generation for residential customers is - 6.7% below the 2024 Rate Case forecast. The updated forecasts for 2026 and the 2027/2028 Test Period are also significantly lower than 2024 Rate Case forecasts for these periods. These differences reflect the fact that actual adoption of PV systems in 2025 was below the 2024 Rate Case forecasts for that year.

Overall, the 2024 Rate Case forecast for PV and EV were both higher than the 2026 Rate Case forecast for residential customers. The EV adoption forecasted for this rate case is slower as compared to the 2024 Rate Case, but it is still growing at a steady pace. So, in summary, when comparing the forecasts in the 2024 Rate Case to this rate case, PNM residential sales have increased because the SPC have increased.

Q. What is the estimated Residential average sales per customer used for purposes of performing bill impacts in this case?

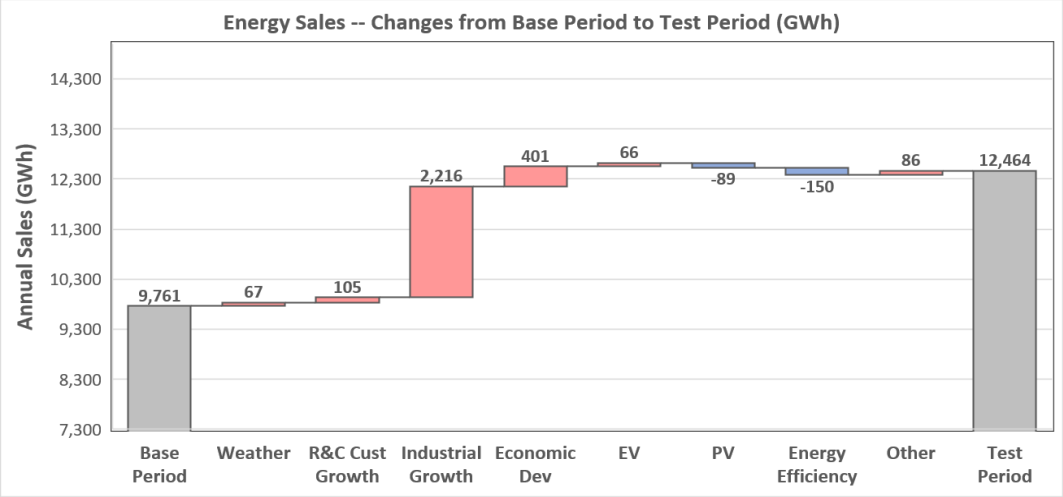
A. PNM is using an estimated monthly average sales per customer of 550 kWh for the Residential Class. This is an approximation from average projected sales for the Test Period of 553 kWh, using the projected annual sales per customer shown above in PNM Figure ATH-7 (i.e., 6,643 kWh/12 = 553 kWh per month). This is a

reduction of 50 kWh in the projected monthly usage that PNM had used in previous rate cases.

Q. Can you provide a summary of the factors that are driving the change in total electricity sales.

A. PNM Figure ATH-8 shows a "waterfall chart" that breaks down the components of change between Base Period sales and Test Period sales. Each step quantifies the impact of a category of inputs to the modeling process, and the series of steps provide a bridge across the 2.5-year prediction interval. Overall, there are eight main factors driving the projected change in electricity sales.

PNM Figure ATH-8
Components of Change --Base Period to Test Period



Starting with recorded sales of 9,761 GWh, the first element of change is due to weather. As discussed earlier in my testimony, the combined impact of warmer than normal winter weather and hotter than normal summer weather means 67 GWh

addition. The result is a slight upward adjustment (67 GWh or 0.69%), representing the conclusion that Base Period sales would have been slightly higher under normal weather conditions.

The second component is customer growth in the residential class and the commercial classes SP and GP. The number of residential customers is expected to increase by approximately 2% and commercial customers (SP and GP) are expected to increase by 1%, and this growth is projected to add 105 GWh to Test Period sales, which is 1.08% of total Base Period sales.

The third component, labeled industrial growth, represents increased load expected from expanded operations of LS customers, primarily in rates LS30 and LS36. This increase is 2,216 GWh, which is 22.7% of total Base Period sales.

The next component represents the expected addition of new customers in the LP4 and LP35 classes related to PNM economic development activity. LS5 is added to LP4 in the Test Period due to the proposed rate discontinuation of LS5. For LP4, customer additions are expected to occur in late 2026 (two) and mid-2027 (one), as well as one customer gain for adding the LS5 customer. The gains are expected to add 65 GWh to Test Period sales for LP4, which is 0.67% of total Base Period sales.

The next step upward accounts for sales changes related to incremental adoption of EVs. Based on a combination of market research performed by PNM and a study

performed by the Electric Power Research Institute for PNM, it is projected that over 16,000 additional EVs (passenger vehicles) will be added in the PNM service territory between the middle of the Base Period and the middle of the Test Period. A small amount of additional charging energy is expected from adoption of commercial fleet vehicles and medium/heavy duty vehicles. The combined incremental energy for EV charging between the Base Period and the Test Period is projected to be 65.7 GWh, which is 0.67% of total Base Period sales.

The next step is downward and represents lost energy sales due to incremental adoption of behind-the-meter solar (PV). There are 301 MW of solar generation capacity in the PNM service territory at the end of the Base Period, and this is expected to increase to 390 MW by the end of the Test Period. The 89 MW of incremental PV capacity is projected to reduce Test Period sales by approximately -88.7 GWh, which is -0.91% of Base Period sales.

The next step is also downward and represents reduction in energy sales due to improvements in the energy efficiency of appliances, equipment and buildings. The efficiency gains come from a wide range of end uses, including heating, cooling, water heating, cooking, refrigeration, appliances, and lighting. As discussed above, efficiency changes are based on regional efficiency forecasts from the EIA, which include impacts from standards, utility efficiency programs, and technology change. These changes are expected to reduce Test Period sales by approximately -150 GWh, which is -1.54% of Base Period sales.

The last step, labeled "Other," captures the net effect of the remaining changes, including changes in equipment and appliance saturation levels, miscellaneous end-use load growth, statistically estimated time trends, and the impact of changes in economic and demographic variables on residential sales. The net impact of these factors is projected to add 86 GWh to Test Period sales, an increase of approximately 0.88% of Base Period sales.

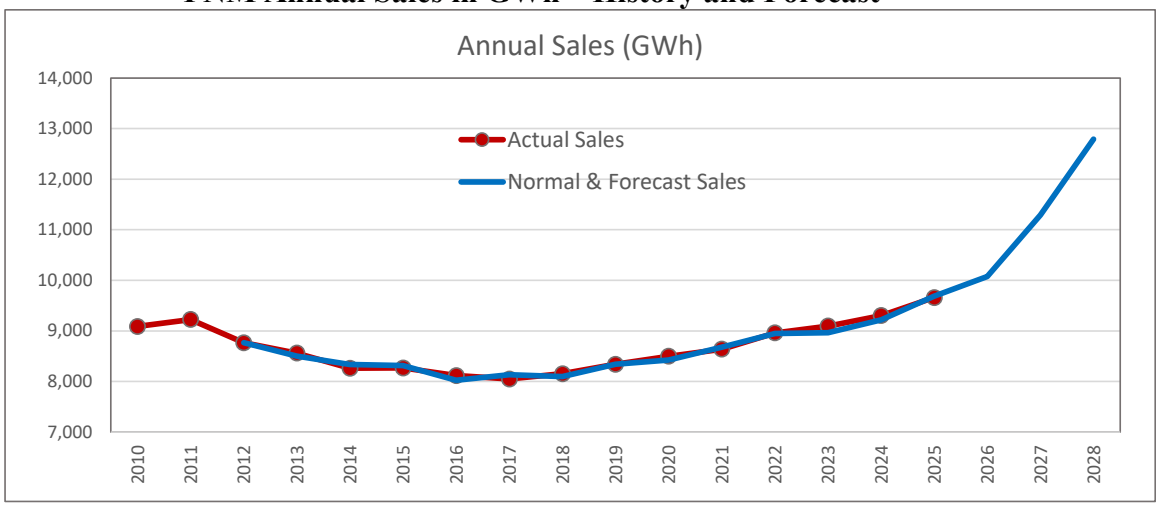
Q. Given the factors that are driving the change in total electricity sales, what is the sales forecast for the Test Period and how does that forecast compare to historical sales?

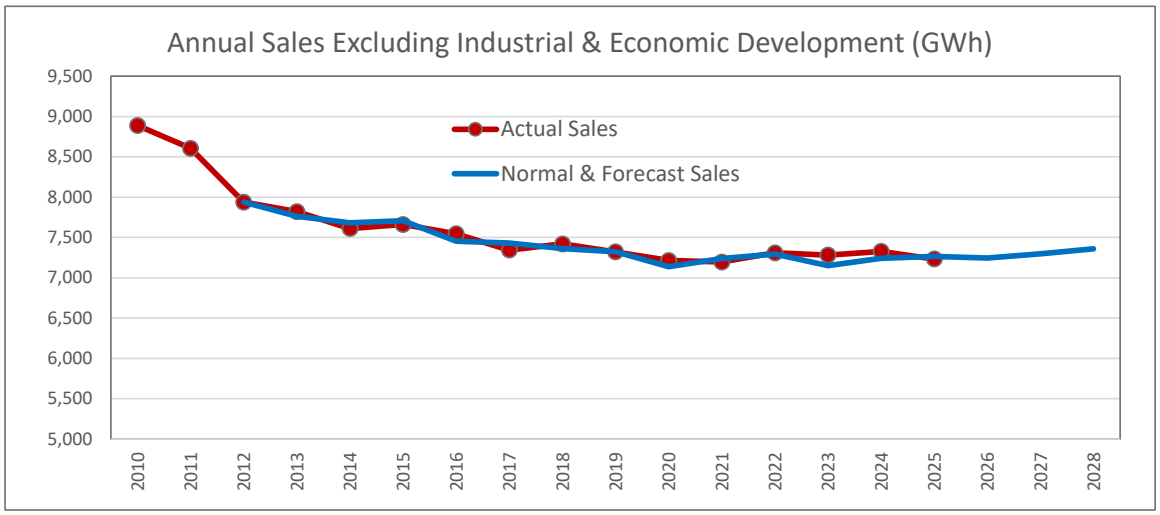
A. The resulting forecast for Test Period sales is 12,464 GWh, which is a 27.7% increase relative to Base Period sales. To put this in perspective, PNM Figure ATH-9 shows the history and forecast for annual sales from 2010 through 2028. This figure shows actual annual sales values in red through 2025. The blue line shows weather-adjusted sales for 2012 through 2025 and projected sales with normal weather through 2028.

The top chart in the figure shows total sales and the bottom chart shows total sales less large service sales (for example, Rate Schedules 5B, 15B, 30B, 33B, 35B and 36B) and economic development gains in Rate Schedules 4B and 35B. From the comparison, it should be clear that historical and forecast sales growth since 2018 is entirely due to large commercial service or industrial sales gains. The forecast reflects continued customer growth in the residential class. However, the impacts

of energy efficiency, behind-the-meter solar adoption, and evolving customer behavior are expected to offset underlying load growth, resulting in relatively flat sales across other customer classes. More specifically, the bottom chart shows the steady decline in residential and small commercial sales, largely driven by energy efficiency gains and increased adoption behind the meter solar systems. In summary, annual sales are flat for all classes if we exclude growth resulting from the Large Service customers' classes and economic development.

PNM Figure ATH-9
PNM Annual Sales in GWh – History and Forecast





VIII. FRAMEWORK FOR HOURLY LOAD PROJECTIONS

Q. What is a "system peak" for a utility?

A. A utility's system peak is the date and time when the utility's entire system reaches its highest demand. The PNM system peak tends to occur in the late afternoon on a hot summer weekday.

Q. Can you explain the terms noncoincident class peak ("NCP") and coincident peak ("CP")?

A. For a customer class, the NCP is the combined load of all customers in that class on the day and hour when the customer class's combined load is at its highest level, or "peak." Class peaks typically do not occur in the day and hour that the PNM system reaches its highest value, thus the use of the word noncoincident. In contrast to the PNM system peak, residential class peaks often occur on a weekend day with hot weather. Non-residential class peaks normally occur on a hot weekday in the early afternoon. Industrial class peaks tend to occur in an hour when production is high. Lighting class peaks occur at night.

CP for a class is the class load at the time of the system peak. The CP value will be smaller than the NCP value in most cases, unless the class peak happens to occur at the same hour and day as the system peak.

Q. Are NCP and CP values measured or projected?

A. Hourly measurements are available for individual customers in the large commercial service and industrial classes (LP4, LS5, LS15, LS30, LS33, LP35). Water (Rate Schedule 11) also has many customers with hourly meters, but some meters for these groups are monthly billing meters that provide no hourly measurements. For residential and smaller commercial classes (Res, SP, GP), most meters are monthly billing meters. For these classes, PNM has installed hourly meters for a statistical sample of customers, called a Load Research sample. For

these classes, the PNM Load Research staff performs statistical expansion calculations to project the hourly class loads based on the measured hourly loads of the sampled customers.

The NCP and CP projection developed for my testimony use both the measured data for the classes with hourly meters and the load research estimates for the sampled classes.

Q. How are the hourly load data used in the modeling process?

A. The historical hourly load data for large customers and the hourly load research estimates are used for two purposes. First, these data are used for each class to estimate weights that are used to combine low-powered, medium-powered, and high-powered degrees into weighted weather response variables for the monthly sales models. Second, the hourly load data are used to project hourly class profile models. These models relate class load in each hour to daily weather conditions and calendar conditions. Once projected with historical data, these models are used to project hourly customer load shapes for all classes.

Q. How are normal weather data constructed for the hourly load projections?

A. The 10-year historical weather period that is used to construct normal weather values for the monthly energy use projections is also used to define normal weather for the hourly load shape projections. Although the historical weather data are the same, the processing steps are different for these two uses. For the monthly energy

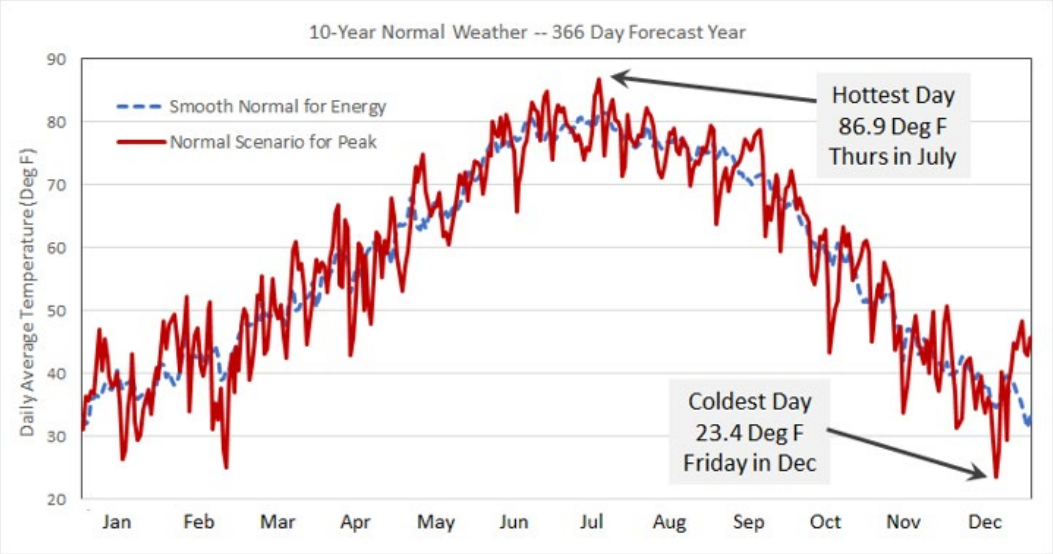
use models, we used an "average-by-date" method. This process creates a relatively smooth normal pattern, like you would see in the newspaper as the normal average temperature for each month of the year. This approach is appropriate for the calculation of weather adjustments to monthly energy and for forecasting monthly energy sales, but it will not work for projecting daily and hourly load patterns because it does not represent typical extremes for hot days and cold days in each month.

For hourly projections, a "rank-and-average" approach is used. This approach sorts the historical daily data for each month from hottest to coldest. Then the hottest temperatures for each month are averaged across the years, giving a typical hottest temperature value for that month. Then the second hottest days for each month are averaged across years. And this proceeds through to the coldest days. For historical years, the resulting range of temperature values for a month is assigned to individual calendar days based on the actual weather pattern in each year. For forecast years, the resulting range of temperature values for a month is assigned to a selected weather pattern that is consistent from year to year. If the calculations are done correctly, the HDD and CDD values at the calendar month and annual level are the same for these two methods (average by data and rank and average).

PNM Figure ATH-10 provides a comparison of the daily average temperature values used for the monthly sales projections (labeled "Smooth Normal for

Energy") and for the hourly load projections (labeled "Normal Scenario for Peak") for the Test Period in this case.

PNM Figure ATH-10
Daily Average Temperature for Normal Weather



Q. Please summarize the steps in the hourly load shape modeling process.

A. Regression models are used to explain hourly UPC as a function of daily temperature, day type, season, holiday schedules, and COVID-19 phase variables. For each customer class, a separate equation is estimated for each hour. These estimated models are then used to project hourly UPC in the Test Period using the normal daily weather. PNM Figure ATH-10 shows normal daily average temperature for the regression models. The UPC projections are then reduced to remove the influence of PV and incorporate the effects of EV, providing projections of PNM system hourly SPC.

Q. How are the hourly SPC projections converted to class hourly load projections?

A. The projected hourly SPC class profiles provide a load shape for each class without incremental EV or PV adoption. For each class, these shapes are combined with projections of calendar month sales that are also projected without incremental PV or EV adoption. The calendar-month sales projections are based on the billing-month sales projections that are discussed earlier in my testimony, but they are adjusted to represent the number of days in the calendar month and weather conditions in the calendar month. The result is a forecast of hourly class loads at the meter without incremental EV or PV adoption. For residential and small power rate schedules, PNM used the load research sample to develop R1A, R1B, SP2A and SP2B load shapes to use in the Test Period.

These hourly load projections are then increased for incremental EV adoption, reflecting the projected number of new vehicles and hourly charging shapes, and reduced for incremental PV adoption, reflecting incremental PV capacity additions and the hourly generation shape. For each class, the result is a projection of hourly load at the customer meter for each hour in the Test Period.

IX. CLASS NCP, SYSTEM LOAD, AND CLASS CP PROJECTIONS

Q. How are the class NCP projections computed?

A. This calculation is simple. The framework provides projections of the hourly class loads. The largest hourly value in each month of the Test Period is the monthly NCP value. The largest of the monthly NCP values is the annual NCP value. These results are all at the customer meter without any adjustment for transmission or distribution losses. The results are shown in PNM Table ATH-6. In the table, the times of the class peaks show the time the peak hour begins ("HB").

PNM Table ATH-6
Class Peak (NCP) Projections

	2025/2026		2027/2028	
Class Definition	**NCP at Meter**	**Date/Time (HB)**	**NCP at Meter**	**Date/Time (HB)**
Residential	952.59	Sat 8/9/2025 16	907.74	Thu 7/20/2028 17
Small Power	238.71	Wed 8/6/2025 14	243.03	Thu 7/20/2028 14
General Power	366.64	Wed 8/6/2025 13	391.69	Thu 7/20/2028 14
Large Power	134.78	Thu 9/18/2025 14	155.57	Tue 6/13/2028 13
Large Service	348.51	Wed 6/24/2026 13	647.82	Thu 9/14/2028 10
Irrigation	5.40	Sat 5/30/2026 16	5.27	Sat 6/17/2028 10
Water & Wastewater	46.56	Sun 8/10/2025 12	41.95	Fri 10/1/2027 09
Private Area Lighting	2.79	Night	2.70	Night
Streetlights	11.09	Night	7.35	Night

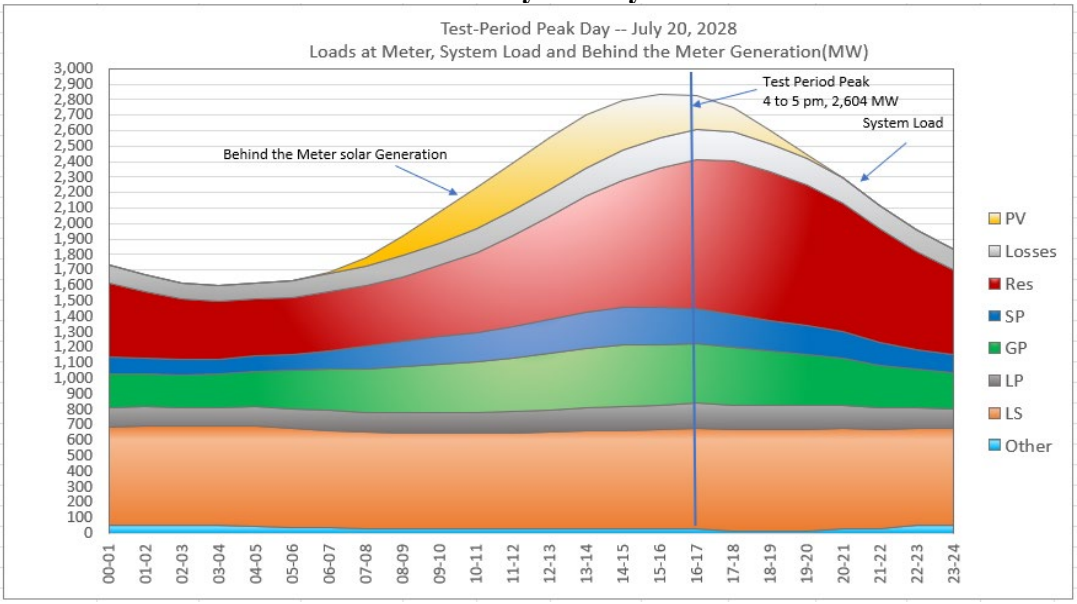
Q. How are the class load projections used to project system loads?

A. The hourly load projections for each customer class are based on measurements at the customer meter (billing data, solar generation data, and load research data). For a given load at the meter, generation requirements will be a larger number because of energy losses in the transmission system, at the substation, or in the distribution system. The first step in the process to project system loads is to adjust load projections at the meter upward to account for the transmission and distribution system losses. This adjustment uses energy loss rates that range from 2.8% for

energy deliveries at transmission voltage levels to 7.7% for energy deliveries at secondary voltage levels.

The class hourly loads, including energy losses, are then added up, providing a bottom-up projection of the hourly system load. For historical years, these hourly sums are then compared to the measured system loads, and a set of calibration factors is computed by month and hour. These calibration factors tend to be largest in the summer months, when losses are higher than average, and lowest in the spring and fall months, when losses are lower. Projected hourly loads at the generation source include both the losses and the calibration adjustments. The results of this process are shown in PNM Figure ATH-11, which shows the hourly loads for the projected peak day in the Test Period (July 20, 2028). The projected system peak is 2,604 MW.

PNM Figure ATH-11
Test Period Peak-Day Hourly Loads



Q. How are the class CP results computed?

A. Based on the system hourly load projections, the first step is to find the projected date and time of the system peak. For the Test Period, this is July 20, 2028, at the hour beginning 16:00 (4 PM) and ending 17:00 (5 PM). Given the date and time for the system peak, the projected class loads at the meter or at the generation source can be identified from the bottom-up class load projections at that time.

PNM Table ATH-7 provides the projected CP values at the generation source (including losses) for the Test Period. Base Period values are also provided for comparison purposes. One important source of change is that the Base Period actual peak is at the hour beginning 16:00 (4 to 5 PM). The projected Test Period system peak also occurs in the hour beginning 16:00 (4 to 5 PM).

PNM Table ATH-7
Test Period CP Values at the Generation Source

	Load at Source at PNM Peak (CP)			
	Wednesday, August 6, 2025 4-5 PM		Thursday, July 20, 2028 4-5 PM	
Class Definition	Base Period	Base Period %	Test Period	Test Period %
Residential	949.95	46.02%	1075.91	41.31%
Small Power	245.52	11.89%	250.04	9.60%
General Power	399.15	19.34%	431.37	16.56%
Large Power	131.21	6.36%	165.31	6.35%
Large Service	298.88	14.48%	649.37	24.93%
Irrigation	4.70	0.23%	5.65	0.22%
Water & Wastewater	34.47	1.67%	26.58	1.02%
Private Area Lighting	0.07	0.00%	0.08	0.00%
Streetlights	0.31	0.02%	0.22	0.01%
Total	2,064.27		2,604.53	

X. BILLING DETERMINANT MODELING FRAMEWORK AND TEST PERIOD PROJECTIONS

Q. What is the next step in the modeling process?

A. The next step, described below, is to derive billing determinants by rate schedules. To arrive at billing determinants, the first step is to take customer class forecasts down to the rate schedule level, which starts with disaggregation.

Q. Can you describe the methods used to disaggregate the customer class forecasts to the rate schedules within each class?

A. The disaggregation methods vary by customer class. For example, for the residential class, Rate Schedule 1A contains more than 99% of the customers. As such, the disaggregation method for this class models the customers and sales for Rate Schedule 1B, which has far fewer customers, and subtracts these values from the class totals to derive forecasts for Rate Schedule 1A. A similar approach is taken for the SP class (to split the totals between Rate Schedule 2A where there are more customers and Rate Schedule 2B where there are fewer customers) and for Irrigation (to split the totals between Rate Schedule 10A with fewer customers and Rate Schedule 10B with the majority of the customers).

For general power (GP), there are five rate schedules, and for billing determinant purposes, a further distinction is required based on voltage level. First, the projections for the commercial EV charging pilot rate (GP3F) are made directly

and subtracted from the total. Next smoothing models are used to forecast customers, and regression models are used to model SPC for the remaining four rates:

- Non municipal, regular load factor (3B)
- Non municipal, low load factor (3C)
- Municipal, regular load factor (3D)
- Municipal, low load factor (3E)

The resulting direct forecasts of customers and SPC are used to calculate sales forecasts for each of the four rates, and these forecasts are used to allocate the remainder of the GP3 forecast to these rates. A final set of regression models is used to split the results for the four rate schedules (3B, 3C, 3D, and 3E) between customers that receive energy at primary voltages versus customers who receive energy at secondary voltages.

Finally, for the large service class, sales models are projected for the individual rate schedules. Predicted values for these models are adjusted based on information provided by the individual customers. Such adjustments are made for LS15, LS30, LP35, and LS36. The resulting predictions are summed across the schedules to produce the class forecast. LS5 rate will no longer be offered in the Test Period, so it is appropriate to combine LS5 with LP4 for the Test Period.

Q. How did PNM calculate Rate Schedule 20 Streetlighting billing determinants?

A. To develop the billing determinants for Rate Schedule 20 Streetlighting, PNM projected the number of lights by type. Within those projections, PNM distinguished between Company-Owned and Customer-Owned lights, as each category has its own corresponding usage for the Test Period.

Q. Can you describe the results for the Base Period and Test Period for number of customers and sales?

A. The results for customers and sales at the rate schedule level are shown in PNM Table ATH-8. The Base Period customer value is the average of the actual monthly customer values for months in the Base Period. The Test Period customer value is the average of forecasted monthly customers in the 12 months in the Test Period. Annual sales values are the sum of actual monthly billed sales for the Base Period and the sum of forecasted monthly sales for months in the Test Period.

PNM Table ATH-8 also shows the percent change in customers and sales in each of the classes. As shown in the waterfall chart in PNM Figure ATH-8, changes in sales are driven by a complex combination of factors. These include weather conditions during the Base Period and their impact on observed sales, customer growth, economic activity, energy efficiency, behind-the-meter solar adoption, electrification, and evolving customer behavior.

Two of the larger sales changes in GWh occur for Rate Schedules 30B and 36B, both of which are based on forecast information provided by the customers. The next more significant change between Base Period and Test Period are Rate Schedules 4B and 35B, both of which are adjusted upward for expected growth related to new customers coming in through economic development efforts and the one Rate Schedule 5B customer moving to Rate Schedule 4B. For Rate Schedules 1B and 2B, all the legacy TOU customers were moved to TOD in the Test Period. Rate Schedule 3F is growing due the projected expansion of charging stations.

PNM Table ATH-8
Sales and Customers by Rate Schedule

Class Definition	Customer Class	Rate Schedule	Description	Base Period Customers	Test Period Customers	Percent Change (%)	Base-Period Sales (GWh)	Test-Period Sales (GWh)	Percent Change (%)
Residential	Res	1A	Energy Blocks	497,175	502,412	1.1%	3,233.6	3,323.2	2.8%
		1B	Time of Use/Time of Day	1,492	8,100	443.1%	13.8	69.2	400.5%
Small Power	SP	2A	Energy	54,128	55,083	1.8%	912.3	937.0	2.7%
		2B	Time of Use/Time of Day	426	522	22.5%	18.6	20.0	7.5%
General Power	GP	3B Sec	Secondary	2,797	2,733	-2.3%	1,318.3	1,320.2	0.1%
		3B Pri	Primary	87	85	-2.1%	110.9	108.5	-2.1%
		3C Sec	Secondary, LLF	1,130	1,251	10.7%	296.0	338.6	14.4%
		3C Pri	Primary, LLF	19.2	22.7	18.5%	22.2	21.4	-3.8%
Municipal General Power	GP	3D Sec	Secondary	152	159	4.7%	91.8	99.2	8.1%
		3D Pri	Primary	8.0	8.0	0.0%	9.8	9.5	-2.6%
		3E Sec	Secondary, LLF	74	68	-8.8%	21.7	22.3	3.1%
		3E Pri	Primary, LLF	5.0	5.0	0.0%	3.2	3.1	-2.0%
Commercial Charging	GP	3F	Time of Use	15	22	50.0%	6.8	10.0	47.3%
Large Power	LP	4B	Utility Owned	61	63	3.0%	240.9	276.3	14.7%
		4B COT	Customer Owned	94	95	0.8%	598.1	706.5	18.1%
Large Service (>8MW)	LS	5B	Mining	1.0	1.0	0.0%	11.7	11.0	-6.0%
Large Service University		15B	University	1.0	1.0	0.0%	67.1	73.2	9.1%
Large Service (>30MW)		30B	Industrial	1.0	1.0	0.0%	621.3	729.9	17.5%
Large Service Stn Pwr		33B	Station Power	1.0	10.0	900.0%	3.1	13.5	337.9%
Large Power (>3MW)		35B	Industrial	4.2	5.0	20.0%	154.6	304.6	97.0%
Special Power		36B	Industrial	1.0	1.0	0.0%	1,733.2	3,839.6	121.5%
Water and Wastewater	Water	11B	Energy	38	38	0.4%	43.8	41.7	-4.7%
Water and Wastewater		11B	Time of Day	114	115	0.4%	131.4	125.1	-4.7%
Irrigation	Irr	10A	Energy	108	109	1.6%	3.3	3.9	17.7%
		10B	TOU	207	206	-0.3%	19.6	20.6	4.8%

Q. Please describe the usage block modeling framework for residential customers and Test Period results.

A. The only rate schedule with usage blocks is residential Rate Schedule 1A. This rate has three monthly usage blocks. The first block has the lowest price for usage up to and including 450 KWh. The second block has a higher price for usage over 450 KWh up to and including 900 KWh. The third block has the highest price for usage over 900 KWh.

Analysis of the data shows a strong and stable relationship between block sales and total monthly sales. For each of the three blocks, a regression model is used with monthly constants, monthly sales, monthly sales squared variables as the explanatory factors. The squared terms are included because the block-to-sales relationship is not a straight line, and the squared term explains this nonlinearity. The resulting block-level predictions are converted to percent shares, and these shares are used to allocate total monthly sales to the three usage blocks.

The block forecasts are more complicated because of the introduction of the WHEV option under Rate Schedule 1A. Customer enrollment in this rate began in the second half of 2023 and increased in the Base Period. Enrollment in this option is forecasted to be 7,474 customers by the end of the Test Period. To encourage charging late at night, WHEV customers get a heavily discounted price for off-peak energy between the hours of 10 PM and 5 AM, seven days per week. The remaining energy is priced through the usage blocks. For most of the WHEV customers, this will result in a direct reduction of block 3 energy.

The block sales forecasts for the Test Period are summarized in PNM Table ATH-9. Block sales values are presented in GWh.

PNM Table ATH-9
Base Period and Test Period Sales by Usage Block

Class Definition	Customer Class	Rate Schedule	Description	Base Period	Test Period	Percent Difference
Residential	Res	1A	Total Sales (GWh)	3,233.6	3,323.2	2.8%
			Block 1 Sales (GWh)	1,966.8	1,969.1	0.1%
			Block 2 Sales (GWh)	785.4	797.7	1.6%
			Block 3 Sales (GWh)	478.5	517.5	8.2%
			WHEV Off Peak	2.9	38.9	1263.5%
			Block 1 Percent (%)	60.9%	59.3%	
			Block 2 Percent (%)	24.3%	24.0%	
			Block 3 Percent (%)	14.8%	15.6%	
			WHEV Off Peak (%)	0.1%	1.2%	

Q. Please describe the modeling framework for sales by the TOU/TOD period and the associated Test Period results.

A. Most PNM rate schedules include a time of use component or option. Unlike the approved TOD Pilot rates, these legacy rates have two TOU periods defined as the on-peak period (8 AM to 8 PM on weekdays) and the off-peak period (all other hours). For the Test Period, monthly class sales are allocated to the TOU periods using a simple ratio approach. For each TOU rate schedule, the historical data are used to compute a monthly on-peak fraction (on-peak sales divided by total sales). Regression models are used to model this fraction based on monthly constants and TOU sales per customer. Models are estimated using monthly data through June 2026. The projected peak fractions for months in the Test Period are used to allocate total monthly sales to monthly on-peak sales and monthly off-peak sales. All legacy

TOU customers in Rate Schedules 1B and 2B are proposed to be placed in the TOD Pilot rate schedules in the Test Period.

Q. Please describe the modeling framework used to project Low-Income and Non-Low-Income determinants for Test Period results.

A. To identify and estimate the usage characteristics of low-income and non-low-income residential customers, the Company utilized household income information obtained from Experian. The Experian data provide estimated household income in defined income ranges, or "buckets," rather than a specific income amount for each household. For example, a household may be identified as having an estimated annual income between $50,000 and $74,999. PNM used the midpoint of the income range to determine low-income eligibility.

Q. How did PNM utilize Experian database to determine low-income eligible customers and how many customers did PNM identify as low-income using the Experian database and federal poverty guidelines?

A. The Experian data were matched with the PNM's Banner billing data using premises and customer identifiers.

The estimated household income was compared with the applicable 2025 U.S. Department of Health and Human Services Federal Poverty Level ("FPL") Guidelines to determine whether each of the customers identified in the billing system would be classified as low-income or non-low-income. The FPL Guidelines

vary according to household or family size.[5] The Company considers low-income customers as those whose income level falls at or below 200% of the FPL Guidelines. Under this criteria, PNM identified approximately 167,000 residential customers, which is about 33% of the residential customers.

Q. Is PNM accounting for all the customers identified in the Experian database as low-income?

A. For purposes of determining the number of billing determinants used to calculate PNM's proposed low-income rate, PNM is estimating that only two-thirds of the population will qualify and apply for low-income rate. That proportion is approximately 22% of residential customers and corresponds to the estimated low-income population receiving Supplemental Nutrition Assistance Program ("SNAP") benefits in the State of New Mexico. Please see PNM witness Aguirre's testimony for more details on the low-income rate.

Q. How is PNM calculating WHEV and Block energy from this information?

A. The Company performed this analysis separately for customers served under the Rate Schedules 1A and 1A-WHEV for the calculated number of customers classified as low-income and non-low-income.

[5] *See* https://aspe.hhs.gov/sites/default/files/documents/dd73d4f00d8a819d10b2fdb70d254f7b/detailed-guidelines-2025.pdf; https://www.dol.gov/sites/dolgov/files/ETA/llsil/pdfs/HHS-Poverty-Guidelines_2025-FRN.pdf.

The Company then evaluated the energy usage associated with each customer classification. Specifically, the analysis determined the proportion of energy consumption in Block 1, Block 2, and Block 3 of Rate Schedule 1A attributable to low-income and non-low-income customers. These calculations were performed separately for the summer and non-summer periods to recognize seasonal differences in customer electricity usage.

Finally, the resulting low-income and non-low-income usage proportions were applied to the Test Period forecast. This methodology provides a systematic approach for estimating the allocation of forecasted residential energy consumption between low-income and non-low-income customers while recognizing the uncertainty inherent in the Experian household-income ranges.

Q. Please describe the modeling framework used to project billing demand and the associated Test Period results.

A. Most of the non-residential rate schedules include a demand charge. The billing demand for a customer in a month is computed from the maximum hourly demand in the on-peak period. Monthly demand for a class is the sum of these customer billing demand values. To model billing demand, the ratio of monthly demand to average load is computed, where average load is billing month sales divided by the number of hours in the billing month.

The definition is:

Demand Ratio = (Billing Demand) / (Average Hourly Sales)

Using measured billing data, a demand ratio is computed for each class in each historical billing month. At the class level, this demand ratio is almost always greater than 1.0, indicating that maximum hourly demand in the on-peak period is greater than the average hourly load.

For the general power class (GP), demand ratios are modeled for four rate schedules (3B, 3C, 3D, and 3E) and two voltage levels (secondary and primary). For the large power class (LP4), demand ratios are modeled separately for customers with utility-owned transformers (4B) and customer-owned transformers (4B COT). Demand ratios for the large rate schedules (15B, 30B, 33B, and 35B) are modeled and projected for each rate schedule.

The demand ratio models are regression models with 12 monthly binary variables, and a set of COVID-19 phase variables as the explanatory factors. Models are estimated using monthly data through June 2026. In some cases, months with anomalous ratios are excluded from estimation.

Q. Please describe the reactive KVA model framework and Test Period results.

A. Reactive kilovolt amperes ("RKVA") are related to power factor adjustments. PNM uses various formulas to calculate RKVA for different rate schedules.

XI. CONCLUSION

Q. Can you please summarize your testimony?

A. My testimony explains the data, assumptions, and modeling methods used to develop the Base Period estimates and Test Period projections that support PNM's allocations and rate case calculations in this case.

For the Base Period, I describe the weather-normalization process used to adjust monthly and annual sales. These adjustments are based on updated monthly use models and normal weather developed from the most recent ten years of weather data (2015-2024). Base Period winter weather was warmer than normal, while summer weather was hotter than normal, resulting in downward sales adjustments in winter and upward sales adjustments in summer. The residential class experiences the largest adjustment because its usage is more sensitive to weather conditions than other customer classes.

For the Test Period, PNM forecasts customer growth, monthly sales, class peaks, coincident class loads at the PNM system peak, and billing determinants by rate schedule. The forecasts incorporate changes in end-use saturation and efficiency using the Statistically Adjusted End-Use (SAE) method, along with the impacts of behind-the-meter PV adoption, transportation electrification, industrial and economic development, and other load drivers. In my opinion, the methods and

forecasts are reasonable and provide a sound foundation for cost allocation and the rate design for the proposed Test Period revenue requirements.

Q. Does this conclude your testimony?

A. Yes, it does.

GCG#536202

PNM Exhibit ATH-1

Statement of Qualifications

Is contained in the following 1 page.

ASLAM T. HAYAT

Education
• Certificate of Completion, Energy Innovation and Emerging Technologies, Stanford University
• Master of Business Administration, Business Administration and Management, Florida International University
• Graduate Certificate in Geographic Information Systems, Saint Mary's University of Minnesota
• Bachelor of Science, Dual majors in Management Information Systems and Business Administration, Winona State University

Employment History
• Manager, Load Forecasting, TXNM Energy, 2025 - Present
• Technical Director, Energy Planning & Forecasting, The Cadmus Group LLC, 2024 - 2025
• Utility Consultant, UI Solutions Group, 2021 - 2023
• Senior Forecaster, Great River Energy, 2016 - 2021
• Senior Forecasting Specialist, Dairyland Power Cooperative, 2014 - 2016
• Load Forecast Analyst, Dairyland Power Cooperative, 2006 - 2013

Certification
• Certified Business Energy Professional (BEP) ID 1134 from Association of Energy Engineers (AEE)
• "The BASICS" Practical Regulatory Training for the Electric Industry, Center for Public Utilities, New Mexico State University

Experience
Mr. Hayat has more than 18 years of experience in electric utility forecasting, integrated resource planning, demand-side management analysis, revenue forecasting, and regulatory support.

His areas of expertise include long-term energy and demand forecasting, econometric and end-use modeling, weather normalization, distributed energy resource analysis, load profile analysis, revenue forecasting, and utility planning.
Mr. Hayat has developed and supported load forecasts for utility planning, budgeting, rate design, resource planning, and regulatory proceedings. He has worked with investor-owned utilities, generation and transmission cooperatives, regional transmission organizations, and utility clients on forecasting and planning matters.

Mr. Hayat is a Certified Business Energy Professional (BEP) through the Association of Energy Engineers. Based on his education, training, and professional experience, he is qualified to testify regarding load forecasting methodologies, forecast assumptions, energy and demand projections, integrated resource planning, and related utility planning matters.

PNM Exhibit ATH-2

Modeling Terminology

Is contained in the following 1 page.

Term	Definition
Binary Variable	A variable that has a value of 0 or 1 depending on conditions. For example, a monthly binary variable for January will have a value of 1.0 if the observation is for January and a value of 0.0 for all other months.
Constant Term	In a linear model (Y = a + bX) the model coeficient (a) is called the model intercept or the constant term. The value of this constant term does not vary over time.
Covid Phase Variables	A set of binary variables introduced to account for shifts in behavior related to the Covid pandemic. The first shift is introduced for April and May of 2020. The second shift is for June through November of 2020. The third shift is for December of 2020 through March of 2021. The fourth shift is for April 2021 and beyond.
Explanatory Factor	In a linear model (Y = a + b X), the variable X is an explanatory factor. Explanatory factors are numerical variables that have a value that changes over time. In a regression model, each explanatory factor has an associated coefficient that is estimated and that determines the contribution of that explanatory factor to projected values.
Exponential Smoothing Model	Exponential smoothing models are time-series models that can be used to project the level, trend, and seasonal pattern of a variable. Projected values depend only on the history of the variable being explained, and there are no other explanatory factors.
Monthly Constant	If a model includes binary variables for individual months, the estimated coefficients for these monthly binary variables are added to the overall model constant for observations in those months. Monthly constants based on monthly binary variables are included in models to account for seasonal patterns in the data.
Regression Model	Regression models are linear models of the form Y = a + bX. Y is the variable to be explained. The first coefficient (a) is the intercept or constant term. The second coefficient (b) is the slope or multiplier on the explanatory factor (X). A multivariate regression model has more than one explanatory factor. The model is estimated by finding the coefficient values that minimize the sum of squared model errors.

BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

IN THE MATTER OF THE APPLICATION OF PUBLIC SERVICE COMPANY OF NEW MEXICO FOR REVISION OF ITS RETAIL ELECTRIC RATES PURSUANT TO ADVICE NOTICE NO. 667	)	**Docket No. 26-0000XXX**
PUBLIC SERVICE COMPANY OF NEW MEXICO,	)	
Applicant.	)	

AFFIRMATION

I, Aslam T. Hayat, submit this unsworn affirmation pursuant to Rule 1.2.2.35(A)(3) and state, upon penalty of perjury under the laws of the State of New Mexico, that I have read the foregoing Direct Testimony and that the statements contained therein are true and correct based on my personal knowledge, information and belief.

Dated: November 24, 2026.

/s/ *Aslam T. Hayat*
ASLAM T. HAYAT

GCG#536035